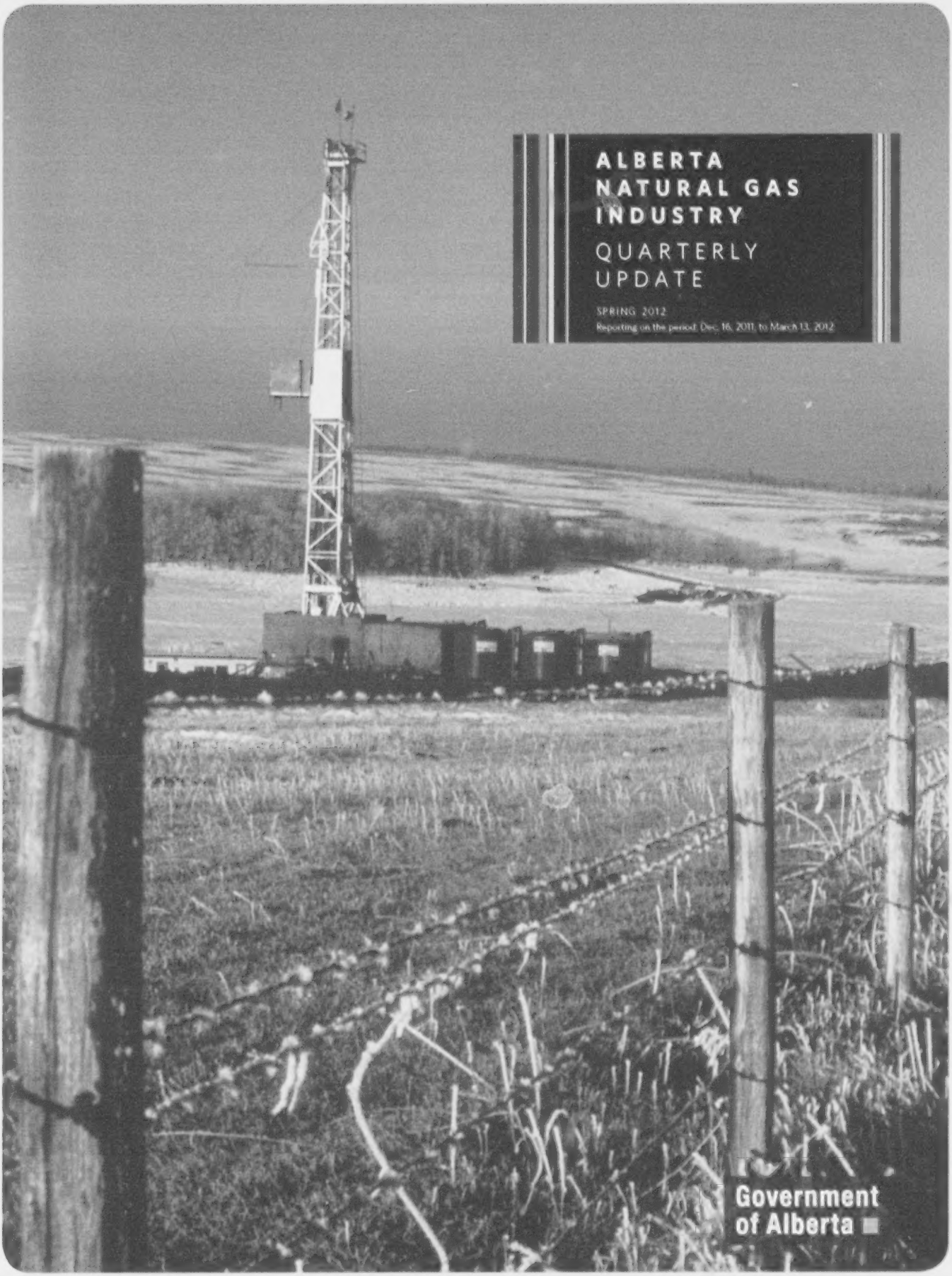

ALBERTA NATURAL GAS INDUSTRY QUARTERLY UPDATE

SPRING 2012

Reporting on the period: Dec. 16, 2011, to March 13, 2012

Government of Alberta

All about natural gas

Background of an important western Canadian resource

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Natural gas has been a key part of the Canadian economy and energy mix for many decades, and the Western Canadian Sedimentary Basin (WCSB)—and more specifically Alberta—has led the way.

Canada is the third-largest natural gas producer in the world, with about 80 per cent of the country's gas being produced in Alberta. In 2010, Alberta produced 4.1 trillion cubic feet of marketable natural gas, including production of approximately 3.8 trillion cubic feet from conventional sources and 0.3 trillion cubic feet from coalbed methane (CBM).

According to provincial figures, at the end of 2010, remaining established reserves of conventional natural gas stood at 36.4 trillion cubic feet while remaining established CBM gas reserves stood at 2.4 trillion cubic feet. Reserve additions as a result of new drilling replaced 46 per cent of 2010 gas production. The province estimates the remaining ultimate potential of marketable conventional natural gas at 74 trillion cubic feet.

Although conventional natural gas remains a very important part of western Canadian production and Canada's natural gas supply, a new era is upon us. The industry has now advanced new technology, such as horizontal drilling and multistage fracturing, to the point that allows for development of natural gas from a new source—unconventional natural gas resources. Aside from CBM, Alberta's unconventional natural gas resources include tight gas (natural gas trapped in low-permeability sedimentary rocks, such as sandstone or limestone) and shale gas (trapped in shale rock).

The Canadian Society for Unconventional Resources has estimated that the recoverable, marketable portion of Canada's unconventional resource is from 376 trillion cubic feet to 947 trillion cubic feet. Remaining gas in place in conventional reservoirs is estimated to be 692 trillion cubic feet, and 357 trillion cubic feet of that resource is expected to be recoverable and marketable, with a total marketable resource from both conventional and unconventional resources of 733 trillion cubic feet to 1,304 trillion cubic feet.

Most of the unconventional natural gas resources occur within the WCSB, a thick package of oil- and gas-prone rocks that cover much of Alberta, Saskatchewan, parts of British Columbia, southwestern Manitoba and northwards into the Northwest Territories.

But there's more to the province's natural gas industry than drilling wells and producing resource, as to make it accessible to Albertans and for export to other markets, a vast infrastructure network is required. Approximately 97 per cent of all oil and gas products move by pipelines in Canada, representing more than three million barrels of crude oil and over 15 billion cubic feet flowing every day through Canada's 580,000 kilometres of pipelines. And this vital transportation network is centred largely in Alberta.

Approximately 70 per cent of natural gas produced in Alberta is exported to other provinces and the United States. Alberta is the largest supplier of natural gas to the United States and currently delivers all of its exports (excluding Canadian provinces) to its southern neighbours, the majority of which goes to the Midwest. Disposition of Alberta's natural gas production in 2010 was approximately:

- 45 per cent to the United States;
- 29 per cent within Alberta; and
- 26 per cent to the rest of Canada.

Alberta's natural gas pipelines deliver natural gas across the provincial border to the Canadian Mainline, B.C. System, the Foothills System and others, connecting provincial energy production to locations as far away as the ports of Metro Vancouver and Prince Rupert and various hubs in the United States.

There are over 392,000 kilometres of energy-related pipelines (including oil and natural gas) as well as extensive storage facilities in the province. This infrastructure is an essential lifeline linking Alberta's natural gas resource to national and U.S. markets.

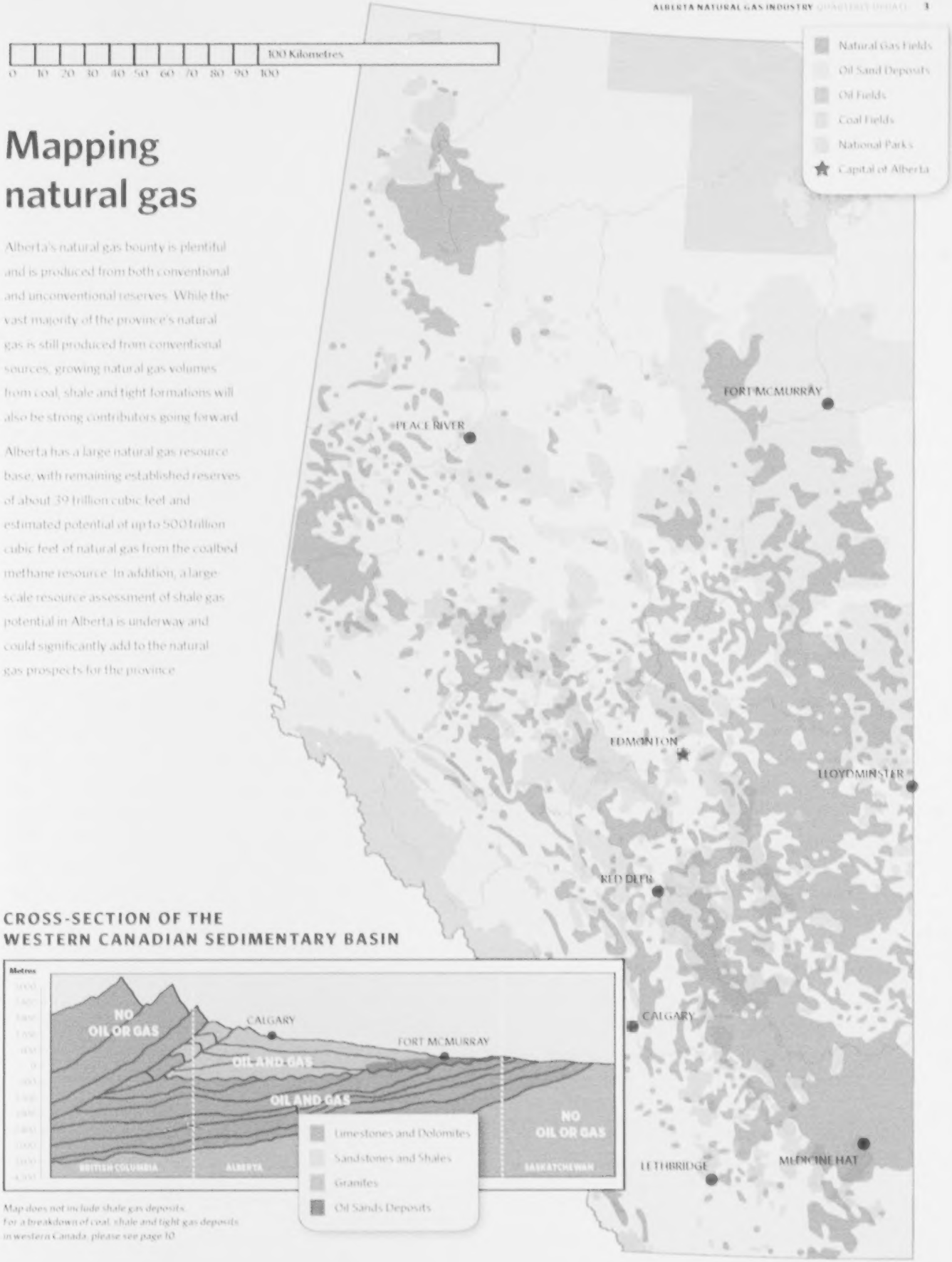
On the environmental front, Alberta has received international attention for its successes in natural gas flaring and venting reductions. Since 1996, solution gas flaring in Alberta has been reduced by 76 per cent. In 2007, the upstream oil and gas industry conserved nearly 96 per cent of all solution gas produced in Alberta for use and sale, rather than flaring and venting it.

By reducing the amount of natural gas that is wasted, Alberta helps ensure that it makes the most effective use of its natural gas resources, and continues the province's record as one of the global leaders in conservation and flaring reductions. ■

Mapping natural gas

Alberta's natural gas bounty is plentiful and is produced from both conventional and unconventional reserves. While the vast majority of the province's natural gas is still produced from conventional sources, growing natural gas volumes from coal, shale and tight formations will also be strong contributors going forward.

Alberta has a large natural gas resource base, with remaining established reserves of about 39 trillion cubic feet and estimated potential of up to 500 trillion cubic feet of natural gas from the coalbed methane resource. In addition, a large-scale resource assessment of shale gas potential in Alberta is underway and could significantly add to the natural gas prospects for the province.



CROSS-SECTION OF THE WESTERN CANADIAN SEDIMENTARY BASIN

Map does not include shale gas deposits. For a breakdown of coal, shale and tight gas deposits in western Canada, please see page 10.

Government update

USE OF NEW TECHNOLOGIES SPURS PROVINCE TO RECORD LAND REVENUES

Capping a record year which saw renewed confidence in Alberta's oil patch, for the first time in provincial history Alberta has exceeded $3 billion in land sales for a calendar year. Revenues for the final calendar year sale of provincial petroleum and natural gas mineral leases and licences, also known as land sales, were $3,145,627 million. This brings the total revenue collected to $3,154 billion for 2011.

Several records were set in 2011. In the August 24 sale, a record was set for the highest price ever paid for a petroleum and natural gas parcel, more than $42.15 million, for a licence southeast of Fox Creek. The June 1 sale netted the highest single-sale record ever, collecting more than $843 million for the province.

Total calendar sales in 2010 were $2.39 billion. This was the first time the province collected more than $2 billion in revenues from petroleum and natural gas land sales.

GOVERNMENT OF ALBERTA TO PARTICIPATE IN NATIONAL ENERGY BOARD HEARING REGARDING TRANSCANADA NATURAL GAS TOLL RESTRUCTURING

The Government of Alberta does not support one element of TransCanada Corporation's application, specifically the Alberta System Extension portion of the proposed natural gas toll reduction, and will participate in the National Energy Board hearing to convey concerns.

The province believes that this portion of the application would result in an inappropriate transfer of costs from TransCanada to Alberta producers and consumers. Alberta Energy estimates that the cost transfer would be about $160 million per year.

Instead of a quick fix, the Government of Alberta is looking for a long-term solution to the challenges associated with the natural gas market. This solution includes a long-term durable toll solution, competitive access to traditional markets, sustaining and potentially increasing Alberta gas production, and fair and equitable sharing of potentially unrecoverable pipeline costs among all stakeholders – all while protecting Alberta consumers and producers.

ERCB ISSUES A DECISION REGARDING NATURAL GAS WELLS THAT PRESENT A RISK TO FUTURE IN SITU BITUMEN RECOVERY

The Energy Resources Conservation Board (ERCB) has issued Decision 2011-035, which concludes that 691 natural gas wells in the Athabasca oil sands area present a significant risk to future in situ bitumen recovery and must be shut in. The gas wells to be shut in are located approximately 300 kilometres northwest of Fort McMurray.

Gas production from these wells may put bitumen recovery at risk. The geological formations in question contain natural gas that is in contact with potentially recoverable bitumen. When this gas is extracted, there is a drop in pressure that may impact bitumen recovery operations that employ extraction methods like steam-assisted gravity drainage.

The ERCB's decision was prompted by applications and submissions from Sunshine Oilsands Ltd., Athabasca Oil Sands Corp. and Total E&P Canada Ltd. for the shut-in of gas production from certain wells. Most of the affected gas wells are licensed to Canadian Natural Resources Limited and Perpetual Energy Operating Corp.

This decision is the result of a public process that included two written, interim hearings held from 2009 to 2011. A final hearing was to be scheduled; however, based on the information that was filed in the interim hearings and with the advice of the hearing participants that no final hearing was required, the ERCB concluded that it had sufficient information to make a final decision.

For the two interim decisions, the ERCB had previously estimated that production of the shut-in natural gas was 1.3 million cubic metres per day (46 million cubic feet per day) in total. The ERCB is satisfied that these estimates remain accurate in the context of Decision 2011-035.

BC LNG GETS 20-YEAR LICENCE TO EXPORT LNG

The National Energy Board (NEB) approved an application by BC LNG Export Co-operative LLC (BC LNG) for a licence to export liquefied natural gas (LNG) from Kitimat, B.C., primarily to Asian markets.

The export licence authorizes BC LNG to export 36 million tonnes of LNG, which is equivalent to approximately 47.9 billion cubic metres of natural gas, over a 20-year period. The maximum annual quantity allowed for export will be 1.8 million tonnes of LNG, which amounts to approximately 2.4 billion cubic metres of natural gas.

A co-operative comprised of natural gas producers, marketers and LNG buyers is a central feature of BC LNG's export proposal, where members of the co-operative will submit bids to either purchase LNG or provide natural gas to be liquefied. A committee will review the bids and choose those that will yield the greatest margin to the co-operative.

Membership in the co-operative is currently comprised of 13 parties, and additional members may join upon request. BC LNG's export model permits smaller natural gas market participants in Canada to play a part in exporting LNG.

In approving BC LNG's application, the board satisfied itself that the quantity of gas to be exported is in excess of the requirements to meet the foreseeable Canadian demand.

The NEB also determined that the volumes of natural gas to be exported are not likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

The NEB acknowledged the potential economic benefits associated with BC LNG's project. In particular, the board noted the benefits for the Haisla Nation, including an interest in BC LNG, and employment opportunities resulting from the development and operation of the liquefaction facility.

This is the second application for an LNG export licence approved by the NEB. In October 2011, NEB approved an application by KM LNG Operating General Partnership for a licence to export liquefied natural gas from Kitimat, B.C., to markets in the Asia Pacific region.

The NEB is an independent federal regulator of several parts of Canada's energy industry. Its purpose is to regulate pipelines, develop energy and trade in the Canadian public interest.

NEB APPROVES NORTHWEST MAINLINE EXPANSION

The National Energy Board (NEB) announced its approval of the Northwest Mainline Expansion Project submitted by NOVA Gas Transmission Ltd. (NGTL).

The project includes the construction and operation of three new natural gas pipeline loops totalling 111.7 kilometres in northeastern B.C. and northwestern Alberta. The pipeline loops would be alongside existing rights-of-way.

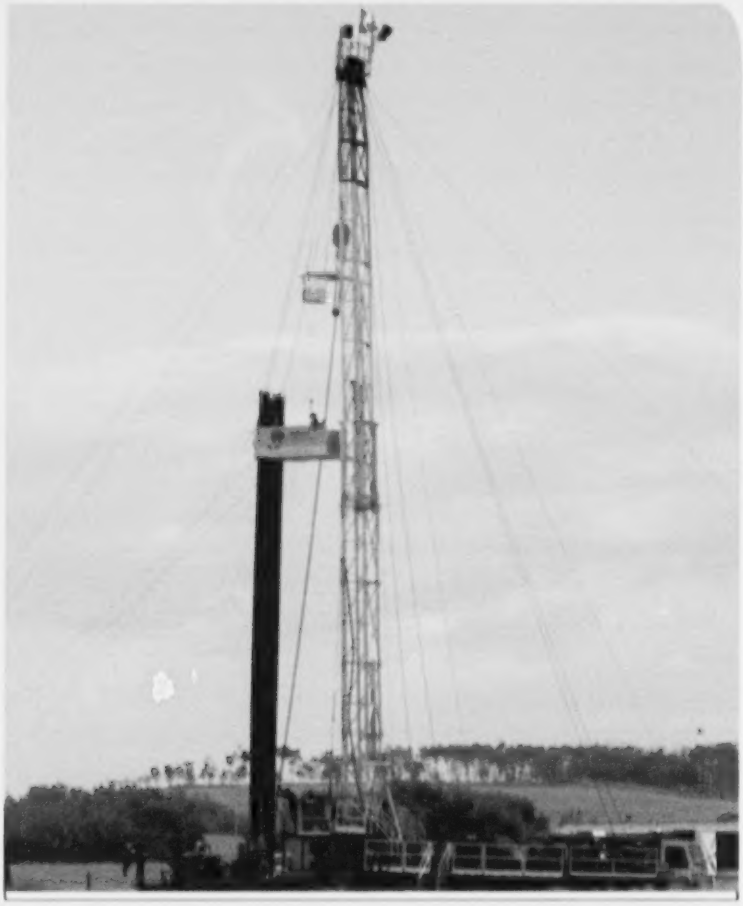
The $324-million project will link natural gas supplies from the Upper Peace River area to markets in Canada and the United States. The board accepts NGTL's submission that there is adequate market demand for the gas to be transported by the project.

The board is satisfied with NGTL's efforts in minimizing potential environmental impacts by proposing a right-of-way that is largely alongside existing rights-of-way. Should the project be constructed, it would not result in new permanent access roads.

The NEB's approval of this project is contingent on conditions that NGTL must meet. The conditions relate to pipeline integrity, the protection of the environment, protection and monitoring of caribou habitat, and matters of public and aboriginal consultation.

The company is required to submit regular updates to the NEB on consultation activities with aboriginal groups and describe how any concerns were addressed. As well, NGTL must provide the NEB with a plan regarding aboriginal participation in construction monitoring.

The NEB issued Hearing Order GH-2-2011 on Jan. 10, 2011, and held a two-day public hearing in Fort Nelson, B.C., starting on Nov. 29, 2011.



NEB APPROVES VANTAGE PIPELINE PROJECT

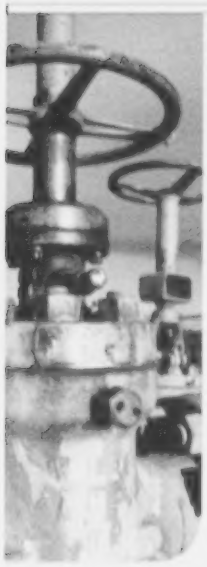
The National Energy Board (NEB) announced its approval of the Vantage Pipeline Project submitted by Vantage Pipeline Canada ULC, formerly Vantage Pipeline Canada Inc.

The $740-million project will carry liquid ethane from Hess Corporation's natural gas processing plant near Tioga, N.D., through Saskatchewan to interconnect with the Alberta Ethane Gathering System (AEGS) near Empress, Alta. The liquid ethane transported by the pipeline will be used by Alberta's petrochemical industry.

The board is satisfied with the evidence provided by Vantage that Alberta's domestic ethane supply is declining and will continue to decline for some time. Vantage demonstrated that there will be sufficient future ethane supplies and processing capacity for the project to be viable over its economic life.

The Canadian portion of the project would involve the construction and operation of approximately 578.3 kilometres of new, 273-millimetre outside-diameter (NPS 10), high-vapour-pressure steel pipeline, from the Canada-U.S. border near Beaubier, Sask., to the AEGS near Empress, Alta. The pipeline route is approximately 527.8 kilometres in Saskatchewan and 43.5 kilometres in Alberta. Vantage has routed the pipeline so that it will be within or alongside existing pipelines and road rights-of-way for approximately 503.7 kilometres. ■

What's new in natural gas



INCREASING NATURAL GAS DEMAND IS KEY

With continued low natural gas prices and supplies from south of the border already squeezing Canadian gas, there are several options being proposed to boost demand for the fuel, including using it to displace coal for electrical generation and increasing its presence in the transportation world.

Michal Moore, a director with The School of Public Policy at the University of Calgary, says there's a big opportunity for natural gas in the electricity market.

"I'll guess that we can get back about 50 per cent of what we've lost over the next 10-15 years in terms of the market share. I'm going to suggest that what will drive that, what will be the capability or the underlying and underpinning market demand for that, is going to be the electric market," he said.

"The world that I see in the future is the gas world. It's not the coal world, it's not likely to be the nuclear world, at least in my lifetime.

"That means that gas will displace in many, many forms some of the things that we find objectionable about the hydrocarbon world, but also some of the things that we found desirable about the alternate world ... That's the world of renewables."

Wayne Gers, vice-president, natural gas economy strategic planning with Encana Corporation, said that despite the short-term challenges with low prices, the future for natural gas is bright. He echoed the fact that it can displace coal and also touched on the possibilities in transportation, although the latter, he noted, will take time.

Encana recently opened the first LNG fuelling station in Louisiana. The station, located in Emerson, which will serve the fuelling needs of heavy-duty truck fleets, is open for public use (to those with an LNG vehicle and proper safety training). The station is currently being used by Heckmann Water Resources, an Encana partner in water sustainability in the natural gas industry.

"That's going to be a long, long haul," he said of the use of natural gas in the transportation sector. "It takes a long time for the market to adapt to new uses of energy, particularly the manufacturing of new end-use equipment, be it big trucks, small vehicles, rail cars, marine ..."

Another choice is exporting LNG off the west coast of North America, and Encana is involved in this respect with a 30 per cent stake in the proposed KM LNG Operating General Partnership, or Kitimat LNG export facility. It's also 40 per cent owned by managing partner Apache Canada Ltd. and 30 per cent held by LNG Resources, Inc.

Kerry Gray, manager, natural gas advocacy with the Canadian Association of Petroleum Producers, said an alarming aspect is that the United States is going to need less Canadian gas because of its own ballooning production.

"That's our biggest market," he said. "When you look at demand creation within Canada outside oil sands, we've got power generation, we can potentially displace coal and there's the natural gas vehicle space.

"LNG exports are a tremendous opportunity for western Canada to realize its full resource potential. ... We think, obviously, there seems to be very robust resources in place," he added. "People ... are very resourceful in terms of unlocking other resources. I think it would be folly to say we've found as much gas as we're going to find."

Gray believes technology will continue to unlock more resources, "so that's why we think, yes, we should be a player."

"Natural gas production and utilization could play both a central role and a critical role in a clean energy transformation in North America," added Chris Severson-Baker, managing director with The Pembina Institute, noting that it must be produced in a clean and safe manner. He also pointed out that public opposition to fracking is a risk to development of the resource.

Mike Holund, assistant deputy minister, strategic initiatives division with the Alberta Department of Energy, described how quickly the landscape can change.

"Three or four years ago we were looking at Alberta running short of natural gas and being a net importer, potentially by 2030," he said. "We moved to see whether there were ways we could move the oilsands to using less gas.

"Now, we have seen the world has changed," he added. "Some of the things we're currently looking at is getting a good understanding of where all the potential markets are going."

Natural gas vehicles, he echoed, are an opportunity, as are LNG exports.

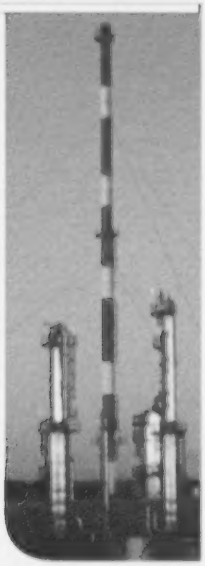
"We're [also] looking at whether or not there might be opportunities for further petrochemical expansion," Holund said.

NATURAL GAS LIQUIDS PRODUCTION STEADY, STORAGE SHORT

Alberta's natural gas liquids (NGL's) production appears to be stabilizing after years of decline, while NGL storage in western Canada – with approximately 17 million barrels of capacity – is definitely in short supply, a recent conference heard.

Steven Paget, vice-president of energy infrastructure at FirstEnergy Capital Corp., said the unprecedented spike in Alberta propane demand during 2010 "was caused by withdrawals for use in oil sands extraction tests.

"I have heard that there is demand for storage approximately equal in capacity of the storage that we already have. The problem is getting the specialty drilling rigs to drill and wash the caverns," he told the Canada & U.S. Western Midstream Summit in Calgary.



First Energy assumes AECO gas prices this summer will drop to $1 per thousand cubic feet, he said. If that happens, they will send many dry gas drilled wells back to zero or below, while rich gas will still return over $2 per thousand cubic feet to the producer, said Paget. "Therefore, rich gas production and liquids extraction will continue."

Each NGL stream has its own supply and demand picture and the data available changes with each commodity, he noted.

"Liquids demand in PADD II still dominates our destiny here in western Canada," he said. "We depend on PADD II demand. It's the one place we have preferential access versus, say, the Gulf Coast, but I'm concerned here that Phase I and II Marcellus Shale gas volumes will have preferential access to PADD II and push back all of us over the next five years."

The approximately 300,000 barrels per day of growth in US ethane production since 2006 is larger than the entire Alberta ethane industry, Paget noted.

Ethane, which is used as a feedstock in petrochemical plants, is in short supply in the province, but First Energy believes the situation will be alleviated within three years.

Meanwhile, butane use in Alberta is down 15 per cent since 2004, said Paget.

Although take-away capacity of NGLs in the United States is currently constrained, 2.1 million barrels per day of new pipeline projects will offer some relief and even some overbuild in some regions, said Jennifer Brickle, a senior energy analyst with Bentek Energy LLC, a U.S.-based energy market information and analytics company.

Oil and gas exports to the Pacific are poised to grow, said Gerry Goobie, managing consultant at Purvin & Gertz Inc., adding the supply outlook depends on demand from oilsands, U.S. exports and LNG exports.

If Pacific basin gas prices remain strong, Canadian LNG exports could exceed three billion cubic feet.

"In the meantime frac spreads are going to be high, everybody's going to go after processing rich gas," he said. "In order to survive, we have to get cost out of the system. Western Canada is a very high cost environment. We'll either do it voluntarily or it will be forced upon us through bankruptcies, and so forth."

PSAC LOWERS 2012 DRILLING FORECAST

The Petroleum Services Association of Canada (PSAC) has lowered its 2012 drilling forecast due to several factors, including weak natural gas prices and labour shortages.

In its first update to the 2012 drilling forecast, PSAC reduced its forecasted number of wells drilled (rig released) across Canada to 13,350 wells. This is a drop of 1,700 (11 per cent) from the industry association's original 2012 forecast released in early November 2011.

However, this still represents an increase of four per cent over final 2011 drilling levels of a total of 12,917 wells drilled across Canada. PSAC is basing its updated 2012 forecast on average natural gas prices of $3.25 per thousand cubic feet at AECO and crude oil prices of US$90 per barrel, West Texas Intermediate, and the Canadian dollar averaging 97 cents.

On a provincial basis for 2012, PSAC now estimates 8,267 wells will be drilled in Alberta, a rise of two per cent over final 2011 drilling numbers. British Columbia is forecast to have 640 wells drilled in 2012, a three per cent rise from last year. Saskatchewan's drilling rate this year will climb by six per cent over last year to 1,739 wells and drilling in Manitoba will climb 11 per cent to 665.

"Due to skilled labour shortages, warm weather hampering the use of heavy equipment, weak gas prices related to oversupply and the ongoing uncertainty created by the European economic debt crisis, we are seeing restricted capacity across the board," Mark Salkeld, president and chief executive officer of PSAC, said in a prepared statement.

"While PSAC's current forecast may be well short of the 20,000 plus well counts we were forecasting only a few years ago, the complexity and depth of current wells will keep our industry well ahead of meeting the increasing demand for oil."

PSAC expects to release its mid-year update on April 25.

Gary Leach, executive director of SLPAC, noted that PSAC's drilling forecast update reflects an assessment of the impact of several influential factors on drilling activity.

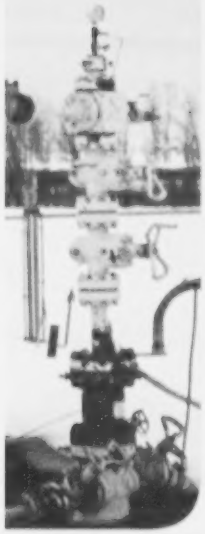
"Leading commodity price forecasts have recently dropped their predictions for natural gas prices significantly, and the winter has proven thus far to be fairly mild with the associated limitations on accessing certain locations and moving equipment," he said.

"As the industry shifts more towards horizontal drilling associated with more sophisticated and expensive completion methods, the sheer number of wells drilled is becoming a less central indicator, although still important, barometer of overall industry activity and financial strength."

NEW OPPORTUNITIES BECKON IN ALBERTA

While the prospect of low natural gas prices for the foreseeable future is not good news, it is creating new opportunities for Alberta companies, says the head of an Edmonton-area industrial development group.

"The good news is that natural gas is a major component of feedstock for a lot of petrochemical and development opportunities," Neal Shelly, executive director of Alberta's Industrial Heartland Association, told the annual stakeholder meeting here last week. "Fertilizers, petrochemicals like ➤



methanol, gas-to-liquids projects, as well as energy production are all looking very positive based on a long-term supply of cheap, abundant natural gas."

At $2.50 per thousand cubic feet, adjusted for inflation, gas has never been cheaper in Alberta, he said.

With the shale gas revolution that has driven down gas prices, there has been a fundamental disconnect between oil and gas prices, making the gas-to-liquids (diesel fuel) process more attractive, said Shelly. The oil-gas price ratio, which for many years was between five and 10, has increased to between 20 and 30 with a barrel of oil today fetching 40 times that of a thousand cubic metres of natural gas.

Talisman Energy Inc., along with partner Sasol Ltd., is looking into the feasibility of building a gas-to-liquids plant somewhere in western Canada and, "this would be a great opportunity for Alberta to get in on the ground floor of what is going to be a revolution around the world."

The petrochemical industry, which was built on low-priced gas as a feedstock, is also beginning to find new sources of feedstock as ethane production from conventional gas production has declined in recent years, said Shelly. Off-gas from oilsands upgraders is starting to become a major player in this area, he said.

Under the Alberta government's Incremental Ethane Extraction Program, The Williams Companies, Inc. invested $300 million to bring off-gas from Suncor Energy Inc.'s operations at Fort McMurray to Williams' processing facility at Redwater. The company now has a deal to sell that ethane to NOVA Chemicals Corporation at Joffre.

Current production of refinery off-gas is 80,000 barrels a day and potentially there could be up to 160,000 barrels a day, said Shelly. "This will not only stimulate the industry, but we are looking at opportunities for future growth in a lot of product chains," he said.

"For the first time in a long time we are starting to hear people in the petrochemical industry talk about growth potential."

In the future, natural gas liquids-rich plays in Alberta, such as the Duvernay, may provide another source of ethane for the petrochemical industry, he suggested.

Alberta's Industrial Heartland, a 582-square-kilometre area near Edmonton specifically zoned for industrial use, is also evolving. The area was once nicknamed "Upgrader Alley" for the large number of oilsands upgraders proposed for the area. The five municipalities in the association now are talking about becoming a global energy processing centre, and hired a consulting firm to identify the best investment opportunities in petrochemicals and companies that might be interested in the Industrial Heartland.

GAS PRICE RECOVERY COULD BEGIN THIS YEAR

This year's warm winter further safe-lantiates leading indicators forecasting an increase in the price of natural gas to at least $5 per thousand cubic feet by the end of this year, says a leading Calgary economist.

"There's a whole bunch of things at play here," said Peter Tertzakian, chief energy economist at ARC Financial Corporation. Leading indicators that gas prices will recover in 2012 – by mid-decade at the latest – include the global increase in gas demand coupled with falling production and insufficient producer cash flow for reinvestment into the commodity, said Tertzakian.

Simple abundance does not mean the price of gas will stay low forever, just as oil's plentitude in Alberta does not keep its price at 50 cents per barrel, said Tertzakian. The real issue is what it costs to produce natural gas and the price at which there is an incentive to look for it, he added.

Global gas demand recently exceeded 300 billion cubic feet per day, which loosely translates as 50 million barrels of oil equivalent per day – growing twice as fast as oil consumption, Tertzakian said.

Asia Pacific demand is rising especially rapidly, he added. The compounded average growth rate over the past five to 10 years is about seven to eight per cent per year with a phenomenal rate of almost 13 per cent from 2009 to 2010, which was before the Japanese nuclear disaster that resulted in that country now importing even more gas.

At least five LNG projects have been announced for the Kitimat, B.C., area with a potential capacity of five or six billion cubic feet of gas per day available before the end of the decade. While Tertzakian firmly believes that they will make a big difference (not only to shippers), not everyone agrees, he acknowledged.

Even one LNG terminal will have significance, he argued. For instance, the LNG project expected to be operational first, the LNG Resources Inc., Encana Corporation and Apache Corporation project in 2015, at one billion cubic feet per day, will handle about 18 per cent of Canada's exports and eight per cent of its total production, he said.

When that occurs, the price of gas will snap up to more than $6 per thousand cubic feet, said Tertzakian, who suggested that such a number seems ridiculous by current standards. "Why wouldn't it be? We've got among the lowest-cost gas in the world now. You look at other parts of the world, whether it's oil or gas, they're low-cost producers relative to other parts of the world and they're capturing high prices and making lots of money, so why shouldn't we?"

LICENCE COUNT RISES IN 2011

With Alberta leading the way, well permitting across Canada increased close to nine per cent in 2011 to 19,813 licences, up from 18,241 wells in 2010 and 17,771 the prior year.

Despite the positive trend, it's still the fourth-lowest tally of the past decade, a period that featured several record years of natural gas drilling.

Industry licensed a record 9,597 horizontal well permits last year (excluding oilsands evaluation and experimental wells), up about 44 per cent from 6,668 licences granted in 2010. Directional licences totalled 3,778, up from 3,793 in 2010.

In western Canada, the 2011 licence count included 11,850 permits to drill for oil or bitumen, 3,154 oil sands evaluation licences and 3,154 well authorizations chasing natural gas or coalbed methane (CBM).

The oil and bitumen count last year was up 35 per cent over the 2010 level of 8,780 permits, as producers increasingly directed their capital budgets to oil and liquids to take advantage of strong crude prices.

Record levels of oil permits were approved in 2011 in Alberta (6,561 versus 4,872 in 2010), Saskatchewan (4,572, up from 3,231 in 2010) and Manitoba (671 versus 678 in 2010).

The gas well count during 2011 was off about 28 per cent from the prior year (4,965 gas and CBM permits in 2010). In 2004 and 2005, over 20,000 gas well permits were licensed per year.

In Alberta, the Energy Resources Conservation Board approved 2,492 gas and CBM wells last year compared to 4,100 in 2010.

The 3,154 oil sands evaluation permits issued in 2011 were up 7.2 per cent from 2,941 licences in 2010.

The top five licensees of new wells in 2011, excluding experimental wells, were Canadian Natural Resources Limited (1,630 permits), Husky Energy Inc. (1,155), Encana Corporation (980), Cenovus Energy Inc. (686) and Penn West Petroleum Ltd. (544).

In December, industry licensed 2,569 new wells, including 1,117 oil sands evaluation permits. The 2,569 permits represent a 15 per cent decline from 3,016 well authorizations in December 2010.

CANADIAN HYDRAULIC FRACTURING OPERATING PRACTICES UNVEILED BY CAPP

The Canadian Association of Petroleum Producers (CAPP) has announced new Canada-wide hydraulic fracturing operating practices designed to improve water management, and water and fluids reporting for shale gas and tight gas development across Canada.

"The hydraulic fracturing operating practices demonstrate the Canadian natural gas industry's continued efforts to ensure responsible resource development and protection of Canada's water resources," CAPP president David Collyer said. "Applying these new operating practices will contribute to improving our environmental performance and transparency over time, both of which contribute to stronger understanding of industry activity and better relationships with the public, stakeholders and government."

Developed by natural gas producers, the hydraulic fracturing operating practices apply to all CAPP members exploring for and producing natural gas in Canada.

In September 2011, CAPP announced the industry's Guiding Principles for Hydraulic Fracturing, which obligate CAPP members to sound wellbore construction, fresh water alternatives, recycling where feasible, voluntary water reporting, fracturing fluid disclosure, and technical advancement and collaboration.

The operating practices announced today support the guiding principles and strengthen industry's focus on continuous performance improvement.

CAPP said it expects the hydraulic fracturing operating practices to inform and complement regulatory requirements.

In its hydraulic fracturing operating practices, the association said Canada's shale and tight gas industry supports a responsible approach to water management and is committed to continuous performance improvement. Protecting the country's water resources during sourcing, use and handling is a key priority for industry, it said. "We support and abide by all regulations governing hydraulic fracturing operations, water use and protection."

In addition, CAPP commits to the following specific operating practices:

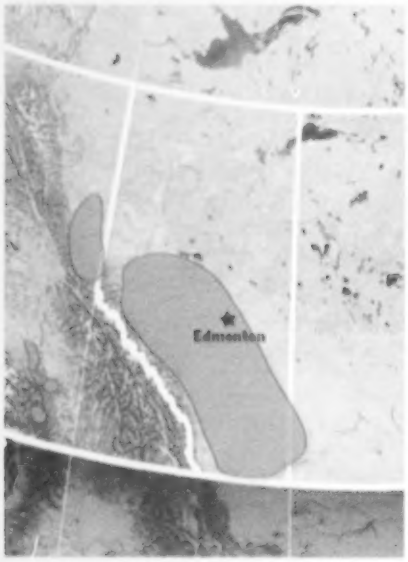
- **Fracturing Fluid Additive Disclosure**. To disclose on a well-by-well basis the chemical ingredients in fracturing fluid additives which are identified on Material Safety Data Sheets (MSDS) for each additive, including trade names, general purpose and concentrations. This information will be made publicly available.
- **Fracturing Fluid Risk Assessment and Management**. To better identify and manage the potential health and environmental risks associated with fracturing fluid additives and ultimately increase the market demand for more environmentally sound fracturing fluids. The process for developing well-specific risk management plans for hydraulic fracturing fluid additives will be made publicly available.
- **Baseline Groundwater Testing**. To develop domestic water well sampling programs and to participate in regional groundwater monitoring programs; to establish a process for addressing stakeholder concerns regarding water well performance; and to continue to collaborate with government and other industry operators.
- **Wellbore Construction and Quality Assurance**. To ensure that wellbores are designed and installed in a manner that maintains integrity before hydraulic fracturing begins, including creating a continuous cement barrier to protect groundwater and developing remedial plans in the unlikely event that a wellbore is compromised. Wellbore construction and quality assurance practices will be made publicly available as they relate to this practice.
- **Water Sourcing, Measurement and Reuse**. To safeguard surface water and groundwater quantity by assessing and measuring water sources, ensuring no withdrawal limits are exceeded, monitoring water sources as required to demonstrate the sustainability of the source, and collecting and reporting water use data. Water measurement, sourcing and reuse practices will be made publicly available.
- **Fluid Transport, Handling, Storage and Disposal**. To identify, evaluate and mitigate potential risks related to the transport, handling, storage and disposal of fluids (i.e. fracturing fluids, produced water, flowback water and fracturing fluid wastes) and ensure a quick response to accidental spills. Fluid transport, handling, storage and disposal practices will be made publicly available. ■

Facts & Figures

Recent information and statistics on the natural gas industry

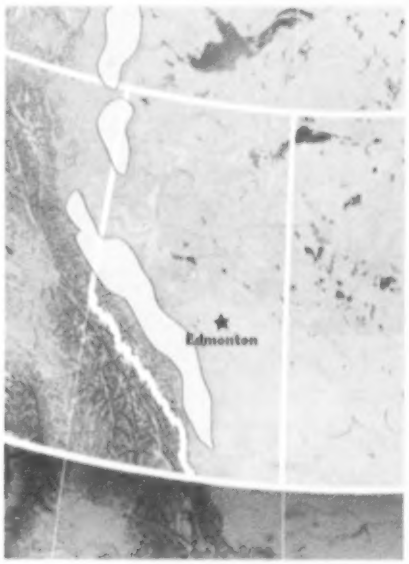
As of December 2011

COALBED METHANE



SHALE GAS

TIGHT GAS



COALBED METHANE (CBM):

The Alberta Geological Survey estimates there may be up to 500 trillion cubic feet of natural gas in Alberta's coals. It is not known how much of this gas may be economic to produce. As more information becomes available, the production potential will become clearer.

Approximately 95 per cent of the coalbed methane wells drilled in Alberta have targeted the thinner coal seams in the Horseshoe Canyon (gas in place 71 trillion cubic feet) and Belly River coal zones along the Calgary–Red Deer corridor. Wells targeting these seams tend to produce gas with little or no water. The depth range of these coals is 200–800 metres.

Most of the remaining CBM wells drilled have targeted the deeper Mannville coals (gas in place 239 trillion cubic feet). These coals tend to be thicker, deeper and more continuous with substantial saline (salt) water production. The depth range of these coals is 900–1,500 metres.

Despite depressed natural gas prices over the past few years, Encana Corporation, Quicksilver Resources Inc. and other companies are still drilling CBM wells. Encana's second-quarter 2011 CBM production was 476 million cubic feet equivalent per day, which was 12 per cent higher than the second quarter of 2010 as a result of successful drilling, acquisitions and third-party production. The company drilled 320 net wells and brought 538 new wells on stream. For 2011, it plans to drill 450 net wells.

Encana also reports it is doing more pad drilling this year to allay land disturbance concerns in more populated rural operating areas, but also to reduce its supply cost on this resource play to around $3 per thousand cubic feet.

The top producers from the Horseshoe Canyon coals are Encana, Quicksilver, Nexen Inc., and Apache Canada Ltd. Nexen and Trident Exploration are the leaders in the Mannville coals.

According to an Energy Resources Conservation Board's (ERCB) 2010 summary of reserves and production, CBM contributed 261 million cubic feet and "activity in CBM has increased from a few test wells in 2001 to more than 16,000 producing connections [wells] in 2010."

Currently, 86 per cent of producing CBM wells are in the Horseshoe Canyon. In 2010, CBM contributed eight per cent of Alberta's total marketable gas production, which the ERCB projects will increase to 13 per cent by 2020.

SHALE GAS:

Shale gas exploration and development in the Western Canadian Sedimentary Basin has undoubtedly been accelerated by the continued success of several prolific U.S. shale basins.

The potential for Canadian shale gas production is still being evaluated. In northeastern British Columbia, the most advanced shale gas plays are found in the Horn River Basin, and to a lesser extent in the Cordova Embayment. A number of companies exploring in these regions have advanced their exploration efforts to a point where pilot projects with multiple wells have been completed and natural gas is being produced.

and sold via the Spectra pipeline system. Large-scale commercial development will be dependent on market conditions.

According to the ERCB, shale gas exploration and production is in its infancy in Alberta, so currently there is limited data to estimate the shale gas resource potential in the province. Knowledge obtained from American projects indicates that shale gas has the potential to add substantially to Alberta's resource and reserve base. The ERCB is currently evaluating the shale gas resource potential of all prospective shale gas formations in Alberta.

Current exploration and production is constrained by poor market conditions, but two new emerging plays in Alberta are the deep Duvernay Formation and Colorado Group shales located in the western part of the province. Limited testing has taken place with encouraging results, but no commercial projects have been developed to date.

TIGHT GAS:

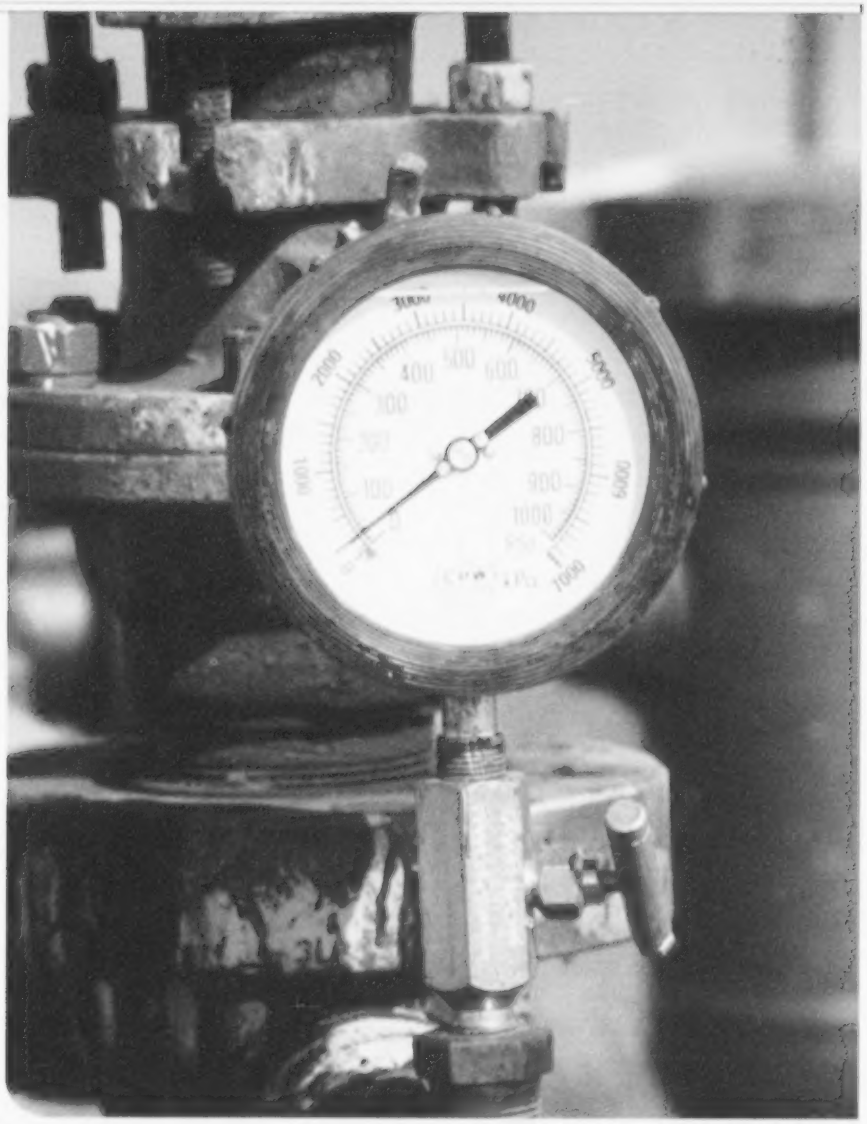
The Western Canadian Sedimentary Basin is host to most of Canada's conventional natural gas resources and within this basin, the northern and western regions contain much of the tight gas potential.

Total original gas in place (OGIP) is estimated at 1,311 trillion cubic feet. Other regions within Canada, specifically the Mackenzie Delta in the Arctic and the Albert Formation in the Maritimes, are believed to have tight gas resource potential, but no estimates have been made due to lack of geological data.

While the OGIP value is very large, only a portion of these resources are deemed technologically recoverable. Marketable resources are estimated at between 230 and 509 trillion cubic feet, with half attributed to the Deep Basin and the Montney in Alberta, and the rest to various accumulations in northeastern British Columbia.

NATURAL GAS LIQUIDS (NGLs):

Natural gas liquids (NGLs) are recovered mainly from the processing of natural gas in Alberta. Field gas-processing facilities ensure that natural gas meets the quality specifications of the rate-regulated natural gas pipeline systems, which require removal of NGLs to meet pipeline hydrocarbon dew point specifications. Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated in specification products. Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas and are usually located on the main gas transmission pipelines at border delivery points.



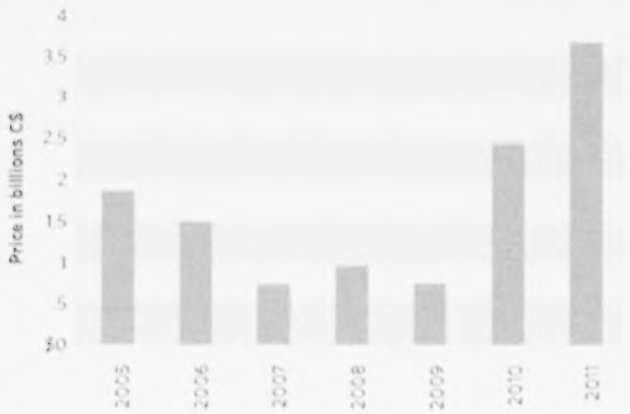
In Alberta, there are about 550 active gas processing plants that recover NGL mix or specification products, 10 processing plants that fractionate NGL mix streams into specification products and nine straddle plants.

Remaining established reserves of extractable ethane is estimated to be 113 million cubic metres (716 million barrels). The remaining established reserves of other NGLs—propane, butane and pentanes plus—is 148 million cubic metres (932 million barrels).

All of the specification ethane extracted from natural gas was used in Alberta as feedstock. The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four plants using ethane as feedstock for the production of ethylene. The petrochemical industry in Alberta is benefiting from the low gas price environment since the price of ethane is linked to natural gas prices. The Alberta ethylene industry continues to maintain its historical cost advantage for ethylene production compared to other regions in North America. ■

ALBERTA CROWN LAND SALES

P&NG rights, excluding oil sands



DRILLING RIG COUNT BY PROVINCE/TERRITORY

Western Canada March 6, 2012

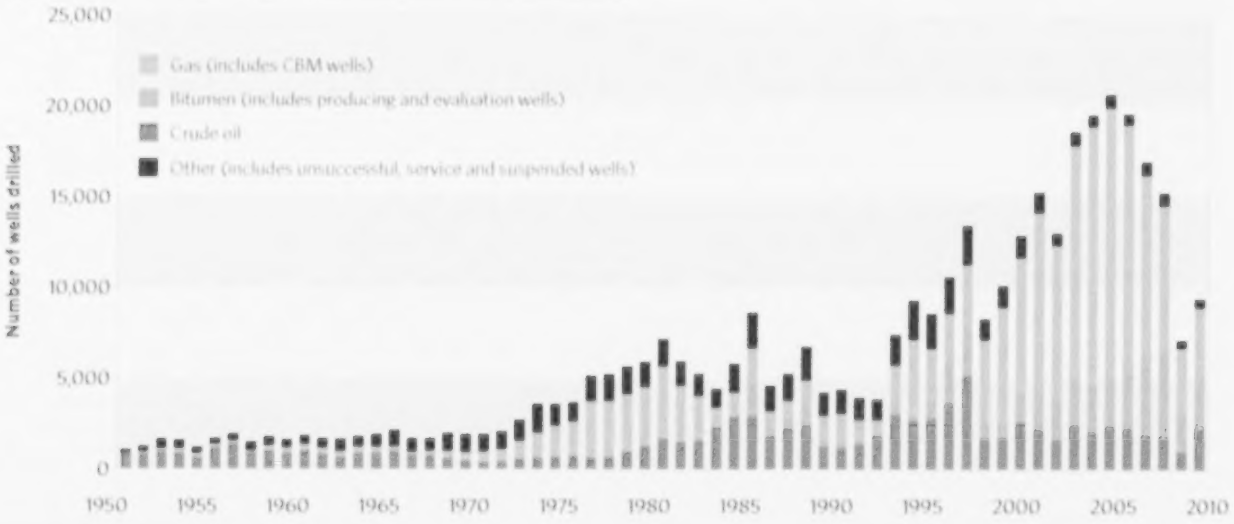
	ACTIVE	DOWN	TOTAL	ACTIVE
Western Canada				(Per cent of total)
Alberta	453	126	**579**	78%
British Columbia	49	12	**61**	80%
Manitoba	19	3	**22**	86%
Saskatchewan	107	17	**124**	86%
WC Total	**628**	**158**	**786**	**80%**
Northwest Territories	1	0	**1**	100%

OIL & GAS WELL COMPLETIONS BY PROVINCE/TERRITORY

Western Canada February 2012

	OIL WELLS		GAS WELLS	
Western Canada	**February 2012**	**February 2011**	**February 2012**	**February 2011**
Alberta	488	357	182	299
British Columbia	2	1	61	78
Manitoba	57	47	0	0
Saskatchewan	296	321	6	6
Total	**843**	**726**	**249**	**383**
Northwest Territories	0	0	0	0

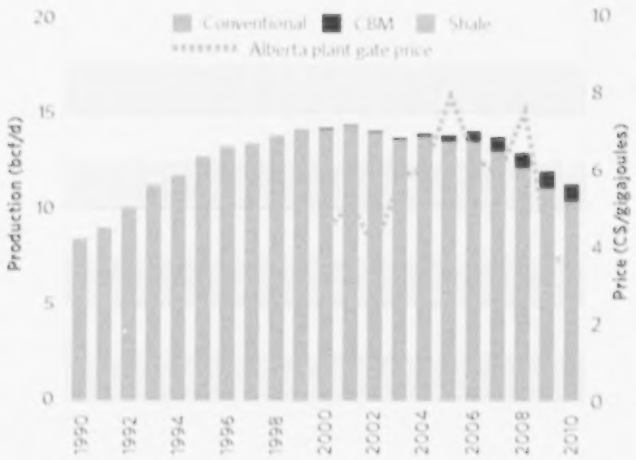
DRILLING ACTIVITY IN ALBERTA, 1950–2010



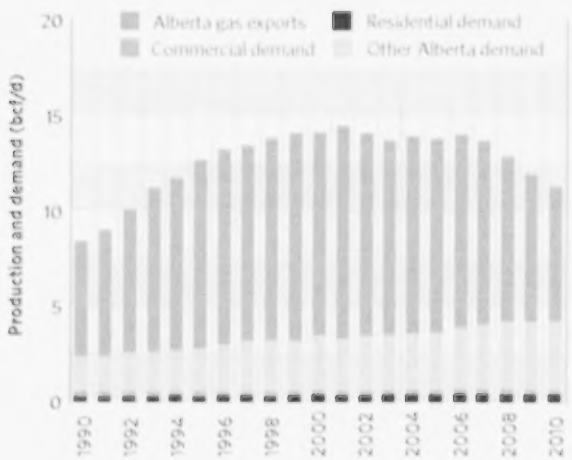
Top 25 Gas Producers in Alberta (as of March 19, 2012)

- Only gas from gas and conventional oil wells was considered; gas from bitumen wells was not included.
- Gas from commercial gas storage schemes was excluded.

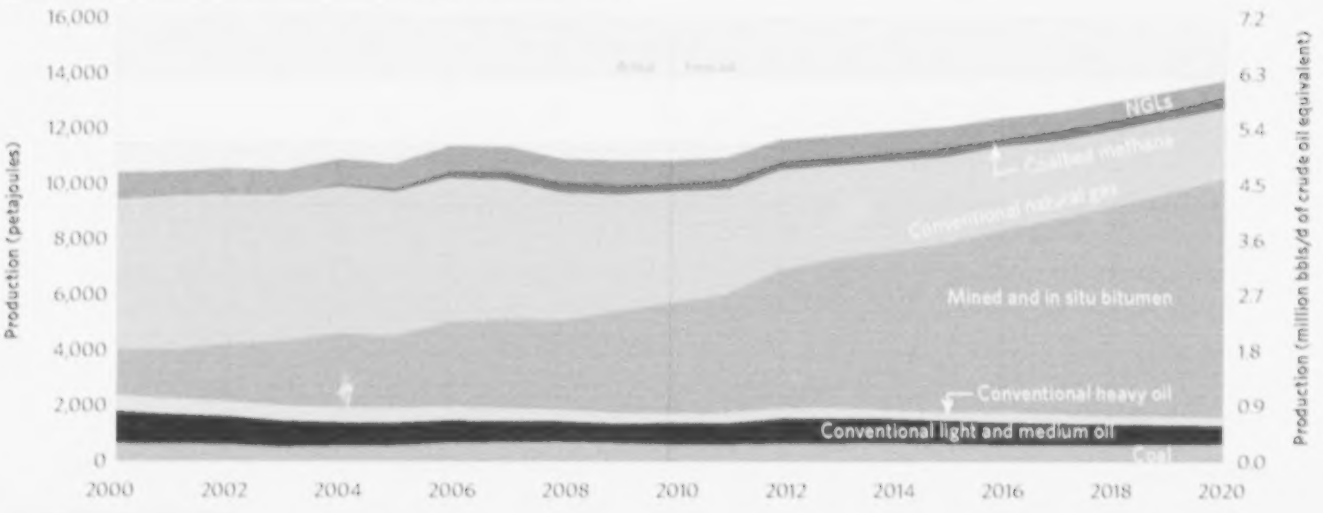
ALBERTA MARKETABLE GAS PRODUCTION



ALBERTA MARKETABLE GAS DEMAND



TOTAL PRIMARY ENERGY PRODUCTION IN ALBERTA



Glossary of natural gas terms

Abandoned well:
A well that is permanently shut down because it was a dry hole or because it has ceased to produce crude oil or natural gas.

Acid gas:
Hydrogen sulphide (H_2S) or carbon dioxide (CO_2) or a combination of H_2S and CO_2, which are referred to as acid gases because they form acids or acidic solutions in the presence of water.

Audits:
Actions taken by staff or a third party to help measure a company's compliance with legislation and internal requirements, and to identify opportunities for improvement. Audits can involve field inspections, interviews with management and document review.

Blowout preventer (BOP):
Equipment that is installed at the wellhead to control pressures and fluids and to prevent uncontrolled fluid flow from the reservoir during drilling, completion and certain remedial operations to restore production.

Broker:
An individual or independent corporation engaged in bringing together sellers and buyers of natural gas, assisting in negotiations, and arranging transportation and delivery terms. Brokers usually do not buy or sell for their own account, but act as an agent for the buyer and/or seller.

Burner-tip:
The point of end-use consumption of a particular fuel, such as natural gas or residual fuel oil.

Burner-tip price:
The price of natural gas (or other fuels) paid by the final consumer. For natural gas, this includes the price of the gas plus the cost of processing, gathering, transmitting and distributing it.

Butane (C_4H_{10}):
A natural gas liquid (NGL) used as a household fuel, refrigerant and aerosol propellant and in the manufacture of synthetic rubber.

Caprock:
Impermeable rocks such as shale that overlie the reservoir rock and trap natural gas and crude oil in the reservoir. Also, impermeable rock overlying a geothermal reservoir. Also called sealing rock.

Carbon dioxide (CO_2):
A non-toxic gas produced from decaying materials, respiration of plant and animal life, and combustion of organic matter, including fossil fuels; carbon dioxide is the most common greenhouse gas produced by human activities.

Carbon monoxide (CO):
Colourless, odourless, poisonous gas produced by incomplete combustion of fossil fuels.

Coalbed methane:
Natural gas generated during the coalification process and trapped within coal seams, commonly referred to as natural gas from coal.

Commingled gas:
A homogeneous mix of natural gas from various physical (or contractual) sources.

Completion:
Preparing a newly drilled well for production; usually involves setting casing—pipe that lines the interior of a well to prevent caving and protect against groundwater contamination—and perforating the casing to establish communication with the producing formation.

Compressed natural gas (CNG):
Natural gas in its gaseous state that has been compressed to about one per cent of its volume and stored at 20,000–27,500 kilopascals.

Condensate:
A mixture of hydrocarbons consisting primarily of pentanes and heavier liquids extracted from natural gas. While it can be used to make gasoline, jet fuel and other products, it is primarily used in Alberta as diluent.

Conventional gas:
Natural gas that can be produced using recovery techniques normally employed by the oil and gas industry. The distinction between conventional and unconventional gas is becoming less clear. See also *unconventional gas*.

Deep cut:
The processes that recover NGLs from natural gas in excess of amounts required for sales gas to meet pipeline specifications.

Deliverability:
The amount of natural gas a well, field, gathering, transmission or distribution system can supply in a given period of time.

Directional drilling:
Drilling a wellbore at any angle other than vertical; used where the rig cannot be set up directly over the target, or to drill more than one hole from a single location.

Downstream:
The refining and marketing sector of the petroleum industry.

Dry gas:
Natural gas from the well that is free of liquid hydrocarbons, or gas that has been treated to remove all liquids; pipeline gas.

Energy Resources Conservation Board (ERCB):
An independent, quasi-judicial agency of the Government of Alberta. Its mission is to ensure that the discovery, development and delivery of Alberta's energy resources take place in a manner that is fair, responsible and in the public interest.

Established reserves:
Generally defined as proved reserves, plus one half probable reserves.

Ethane (C_2H_6):
An NGL, the uses of which include enhanced oil recovery, as a fuel and as a feedstock for the petrochemical industry.

Flaring:
Controlled burning of natural gas that cannot be processed for sale because of technical or economic reasons. The biggest portion is solution gas flaring, which involves the burning of natural gas produced along with crude oil and bitumen.

Fracturing (or fracking):
A reservoir stimulation technique in which fluids are pumped into a potentially productive formation under high pressure to create or enlarge fractures allowing the oil or gas to flow from the zone at higher rates. In some operations, proppants such as frac sand are injected with the frac fluid to help hold the rock fractures open.

Gas:
One of the three states of matter; gas is characterized by having neither shape nor specific volume; it expands to fill the entire container in which it is held.

Gas processing plant:
Any facility that performs one or more of the following: removing liquefiable hydrocarbons from wet gas or casinghead gas; removing undesirable gaseous and particulate elements from natural gas; removing water or moisture from the gas stream.

Gas reservoir:
A porous and permeable rock formation in which natural gas accumulates.

Gas transmission systems:
Pipelines that carry natural gas at high pressure from producing areas to consuming areas.

Gathering system:
A system of small-diameter plastic or steel pipes (gathering lines) transporting natural gas from producing wells to field facilities.

Horizontal drilling:
Drilling horizontally through a reservoir to increase the exposure of the formation to the well.

Hydrocarbons:
A large class of liquid, solid or gaseous organic compounds, containing only carbon and hydrogen, which are the basis of almost all petroleum products.

Hydrogen sulphide (H_2S):
A naturally occurring, highly toxic gas with the odour of rotten eggs.

Inert gases:
Gases that are unable to or unlikely to react with any other substance.

Injection (oil and gas):
Injection enhancement technique wherein water or other substances are injected into an oilfield to improve production. Also, the re-injection of natural gas into an oilfield to maintain reservoir pressure.

Inlet separation:
The initial stage of processing at a natural gas processing plant where the incoming raw gas stream enters a vessel and any free liquids, such as water and NGLs, are removed from the gas stream before it is further processed.

Land:
In the petroleum industry, "land" often refers to the oil and gas rights on a particular area of land. For example, in a "land sale," the oil and/or gas rights are "sold" (although in reality the rights are leased).

Landman:
A male or female member of the exploration team whose primary duties are managing a petroleum company's relations with its landowners and partners, including securing and administering oil and gas leases and other agreements. Other duties include helping to formulate exploration and development strategies. Also known as a land agent or land person.

Lease agreement:
The negotiated legal document giving an oil and gas company the right to utilize the surface lease site to drill for and produce oil or gas.

Liquefied natural gas (LNG):
Supercooled natural gas that is maintained as a liquid at or below -160°C. LNG occupies 1/640th of its original volume and is therefore easier to transport if pipelines cannot be used.

Manufactured gas:
A gas obtained by destructive distillation of coal, by the thermal decomposition of oil or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke or oven gases, producer gas, blast furnace gas, blue (water) gas or carbureted water gas (also known as syngas).

Methane (CH_4):
Methane consists of one carbon atom and four hydrogen atoms and is the largest component of natural gas. Methane remains in a gaseous state at relatively low temperatures and pressures. Methane is also produced when organic matter decomposes.

Midstream sector:
Primarily the processing, storage and transportation sector of the energy industry.

Mineral rights:
The rights to explore for and produce the resources below the surface. In the petroleum industry, mineral rights can also be referred to as "land."

National Energy Board (NEB):
The federal regulatory agency in Canada that authorizes oil, natural gas and electricity exports; certifies interprovincial and international pipelines, and designated interprovincial and international power lines; and sets tolls and tariffs for oil and gas pipelines under federal jurisdiction.

Natural gas:
Gaseous petroleum consisting primarily of methane with lesser amounts of (in order of abundance) ethane, propane, butane and pentane, and heavier hydrocarbons as well as non-energy components such as nitrogen, carbon dioxide, hydrogen sulphide and water.

Natural gas liquids (NGLs):
Liquids obtained during production of natural gas, comprising ethane, propane, butane and condensate.

Non-associated gas:
Natural gas that is produced from reservoirs that contain only natural gas, and is therefore not associated with crude oil production.

Operator:
The company responsible for managing an exploration, development or production operation.

Orphan wells:
Wellsites for which the licence operators have ceased to exist or cannot be traced.

Pentane (C_5H_{12}):
A hydrocarbon compound consisting of five carbon atoms and 12 hydrogen atoms.

Petroleum:
A naturally occurring mixture composed predominantly of hydrocarbons in the gaseous or liquid phase.

Probable reserves:
Reserves believed to exist with reasonable certainty based on geological information.

Propane (C_3H_8):
An NGL used as a fuel (i.e.: in barbeques, transportation and heating of households in areas where natural gas supply is not available).

Proppant:
Sand, or ceramic or resin beads pumped into a wellbore at the end of the fracturing process to prop open newly induced fractures and enhance permeability.

Proved reserves:
Reserves that can be economically produced with a large degree of certainty from known reservoirs using existing technology.

Raw natural gas:
A mixture containing methane plus all or some of the following: ethane, propane, butane, condensates, nitrogen, carbon dioxide, hydrogen sulphide, helium, hydrogen, water vapour and minor impurities. Raw natural gas is the gas found naturally in the reservoir prior to processing.

Recoverable resources:
Hydrocarbon reserves that can be produced with current technology, including those not economical to produce at present.

Renewable energy:
Natural[illegible]curring energy sources that are continually replenished. Examples of renewable energy are wind, solar and water.

Reserves:
Recoverable portion of resources available for use based on current knowledge, technology and economics.

Reservoir (oil and gas):
A porous and permeable underground rock formation containing a natural accumulation of crude oil or natural gas that is confined by impermeable rock or water barriers, and is separate from other reservoirs.

Sales gas:
Natural gas that has been treated in a natural gas processing facility and is suitable for sale. Some of the processes that natural gas may undergo are inlet separation, gas treating, dehydration and NGL recovery, before it enters a transmission pipeline for eventual transportation to market.

Shale gas:
Natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas.

Solution gas:
Natural gas that is dissolved in crude oil in underground reservoirs. When the oil comes to the surface, the gas expands and comes out of the oil.

Sour gas:
Raw natural gas with a relatively high concentration of sulphur compounds, such as hydrogen sulphide. All natural gas containing more than one per cent hydrogen sulphide is considered sour. About 30 per cent of Canada's natural gas production is sour, most of it found in Alberta and northeastern British Columbia.

Source rock:
The rocks in which hydrocarbons are created or sourced from carbohydrates through heat and pressure. Source rocks are often black shales.

Straddle extraction plant:
A gas processing plant located on or near a gas transmission line that removes natural gas liquids from the gas and returns it to the line.

Sulphur recovery:
Sour gas is processed at recovery plants to extract sulphur for sale to fertilizer manufacturers and other industries in Canada and overseas. The average rate of sulphur recovery at Alberta's sulphur recovery plants has improved from 97.5 per cent in 1980 to 98.8 per cent in 2000.

Sweet gas:
Raw natural gas with a relatively low concentration of sulphur compounds, such as hydrogen sulphide.

Syngas:
A fuel produced from solid hydrocarbons such as coal and petroleum coke. The process uses steam, air and controlled amounts of oxygen to break the solid down, and the resulting gas consists of vaying amounts of carbon monoxide and hydrogen.

Tight gas sands:
Natural gas that is found in sandstone with low permeability.

Trunk lines:
Large-diameter pipelines that transport crude oil, natural gas liquids and refined petroleum products to refineries and petrochemical plants; some trunk lines also transport refined products to consuming areas.

Unconventional natural gas:
In the case of natural gas from coal, natural gas from tight sands and shale gas, conventional gas found in unconventional reservoirs or reservoirs requiring special production methods or technologies; in the case of gas hydrates, conventional methane in an unconventional form occurring in a conventional reservoir.

Upstream:
Refers to companies that explore for, develop and produce petroleum resources (in contrast, downstream refers to the refining and marketing components of the industry).

Western Canadian Sedimentary Basin (WCSB):
Canada's largest region of sedimentary rocks; the largest source of current oil and gas production, covering all of Alberta and parts of Manitoba, Saskatchewan, British Columbia and the Yukon.

Wet gas:
Raw natural gas with a relatively high concentration of natural gas liquids (ethane, propane, butane and condensates).

CONTACTS

Industry Associations

• Alberta Land Surveyor's Association	www.alsa.ab.ca
• Canadian Association Geophysical Contractors	www.cagc.ca
• Canadian Association of Oilwell Drilling Contractors	www.caodc.ca
• Canadian Association of Petroleum Producers	www.capp.ca
• Canadian Energy Pipeline Association	www.cepa.com
• Canadian Gas Association	www.cga.ca
• Canadian Natural Gas	www.canadiannaturalgas.ca
• Canadian Natural Gas Vehicle Alliance	www.cngva.org
• Canadian Society of Exploration Geophysicists	www.cseg.ca
• Canadian Society of Petroleum Engineers	www.spec.a.ca
• Canadian Society for Unconventional Resources	www.csur.ca
• Gas Processing Association Canada	www.gpacanada.com
• Petroleum Services Association of Canada	www.psac.ca
• Petroleum Technology Alliance Canada	www.ptac.org
• Small Explorers and Producers Association of Canada	www.sepac.ca

Alberta Government

• Alberta Energy	www.energy.gov.ab.ca
• Alberta Environment and Water	www.environment.alberta.ca
• Alberta Sustainable Resource Development	www.srd.alberta.ca
• Alberta Treasury Board & Enterprise	www.treasuryboard.alberta.ca
• Energy Resources Conservation Board	www.ercb.ca
• Alberta Innovates	www.albertainnovates.ca
• Alberta Geological Survey	www.ags.gov.ab.ca
• Alberta Surface Rights Board	www.surfacerights.gov.ab.ca

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